The Thesis Committee for Allen Thomas Hwang
Certifies that this is the approved version of the following thesis:

The Impact of Cluster Drilling Technology on Well Productivity and Profitability: A Case Study of the Fayetteville Shale Play

APPROVED BY
SUPERVISING COMMITTEE:

Supervisor: ______________________________
Scott W. Tinker

Co-Supervisor: ______________________________
Svetlana Ikonnikova

The Impact of Cluster Drilling Technology on Well Productivity and Profitability: A Case Study of the Fayetteville Shale Play

by

Allen Thomas Hwang, B.S.

Thesis

Presented to the Faculty of the Graduate School of

The University of Texas at Austin

in Partial Fulfillment

of the Requirements

for the Degree of

Master of Science in Energy and Earth Resources

The University of Texas at Austin

May, 2015

Dedication

I dedicate this to my family who has continued to support me through my academic accomplishments. I would also like to dedicate this to my friends for their words of encouragement during my studies.

Acknowledgements

I would especially like to thank my thesis committee members – Dr. Scott W. Tinker and Dr. Svetlana Ikonnikova– for their guidance and mentorship throughout this project. I would also like to thank EER program director Dr. William Fisher for his support and supervision during my pursuit of a Master of Science degree. I am also thankful for the opportunity to be a part of the Bureau of Economics Geology's shale gas research team. The experience has been tremendous.

Abstract

The Impact of Cluster Drilling Technology on Well Productivity and Profitability: A Case Study of the Fayetteville Shale Play

Allen Thomas Hwang, M.S.E.E.R.
The University of Texas at Austin, 2015

Supervisor: Scott W. Tinker
Co-Supervisor: Svetlana Ikonnikova

Horizontal drilling and hydraulic fracturing in shale formations have led to a boom in the U.S. production of natural gas. After the commercial viability of the resource was proven, producers have been focused on innovative completion techniques to increase production and profit. While locations with high resource density and original gas in place can produce sufficient natural gas to make wells economical at relatively low prices, locations with low resource density appear non-viable. The objective of this study is to present an analysis of a new technology–cluster drilling–in the Fayetteville Shale development, highlighting the effect technology may have on well profitability. Inspired by the Fayetteville Shale-Production Outlook performed by the Bureau of Economic Geology (BEG) and funded by the Alfred P. Sloan Foundation, this study uses production history data, separating wells drilled as a cluster from analog non-cluster wells, to investigate changes in costs, production, and profitability. The study's well economics

were analyzed with a discounted cash flow model that reflects how a change in a well production profile and drilling and completion costs will affect its profitability. The study uses individual well estimated ultimate recovery (EUR) projected using methods and well economics parameters reported by earlier studies of the play and investor presentations.

The analysis produced several important results. First, on a per-well basis, non-cluster wells are, perhaps surprisingly, expected to recover more natural gas than cluster wells. Wells in the non-cluster drilling pattern outperform cluster wells in both productivity and profit. However, the well density of cluster drilling results in a higher recovery factor for a given volume of rock, thus a more thorough extraction of the resource. Second, while a cluster pattern produces more gas from a unit of volume, equating to a higher recovery factor, that production comes at higher cost. The analysis reveals the requisite reduction in drilling and completion costs for cluster wells to match profit levels of non-cluster wells in a given lease. Finally, the analysis suggests an operator may choose to forego monetary efficiency, measured by the present value index (PVI), for higher gas recovery factor provided by cluster drilling.

Table of Contents

List of Tables

List of Figures

Chapter 1: Introduction

1.1 Introduction

From 1980 to the early 2000s a widespread discussion in the U.S. was the impending depletion of domestic energy and increasing dependency on imported energy. Many believed the depletion of U.S. energy was due to increasing demand and the industry having already reached the peak of U.S. natural gas production in 1970. At the time this assumption was perhaps understandable, most of the conventional natural gas reservoirs in the country were considered to have been drilled, but lacked the understanding of price, fuel options/demand, and the impact of technology. Without the discovery of new natural gas reservoirs, U.S. production would continue to be outpaced by demand.

That changed around 2000 when the combination of two technologies, hydraulic fracturing (fracking) and horizontal drilling, in shale formations unleashed the resource that is shale gas. Shale is a clastic sedimentary rock that is composed of clay-size minerals, mud, clay, and organic material (Speight 2012). This rock type was widely known in the industry as gas bearing but before 2000, before the use of fracking and horizontal drilling, was not viewed by the industry as a viable resource owing to high costs and low production rates.

Utilization of hydraulic fracturing and horizontal drilling has increased the U.S. production of natural gas to its highest level ever, reported by the U.S. Energy and Information Administration (EIA) as 27 Tcf in 2014 (EIA 2015). This resurgence in US natural gas production is attributed to the abundance of shale gas resources.

After decades of experience, conventional natural gas drilling has been extensively studied. Knowledge of the resource is to the point where good quality conventional gas reservoirs, with an initial pressure of 5,000 pounds per square inch (psi) can be reduced to 1,000psi to recover nearly 80% of the original gas in place (OGIP) (Moniz et al. 2011). The OGIP is the estimated total volume of natural gas in a reservoir (McGlade et al. 2013). In comparison, extracting natural gas from shale reservoirs is in its early stage of development. For example per well recovery factors for Barnett shale gas wells can range from 20-30% of OGIP (Ikonnikova et al. 2014). Therefore, the amount of risk, potential problems, and learning curve in extraction are enormous. Shale is just now being more intensely studied and the intricacies and complexity of the rock are just beginning to be understood. New information regarding shale geology, drilling technology, and completion technology contribute to the complexities in decision-making.

Individual decisions on how to best interpret shale geology, and decisions about how to best drill and complete a well impact the economic viability of a play. A common question in every play throughout the history of natural gas extraction, either conventional or unconventional is: what is the best drilling and completion design. In the past, some operators would drill evenly spaced wells across the entire lease. With new drilling and completion technologies and the ability to mathematically simulate reservoirs, operators can design a variety of well placements for any given lease.

This work further focuses on the relationship between technology and economics. Namely, a well-drilling technology can be evaluated in terms of productivity and profitability. Specifically, the effect of cluster drilling on production and well economics is examined in the application to the Fayetteville Shale. Cluster wells are defined as a tight grouping of wells drilled as a unit: several wells are drilled and completed together in a similar fashion in an attempt to better stimulate a formation and increase the recovery from a unit volume of rock. In the Fayetteville Shale there are often three to five tightly spaced wells in a cluster compared to just one to three wells in non-cluster spaced well grouping. Non-cluster wells are often drilled as a single well or a group of two to three wells spaced further apart than cluster wells. The decision for lease operators on which type of well completion they use, cluster or non-cluster, is not a trivial one. Drilling of a cluster requires a higher upfront investment cost given that several wells are drilled together, and cluster drilling also implies a larger number of wells are drilled per unit of surface area. Hence, an operator faces a trade-off between higher upfront costs and higher production vs. lower costs and lower production. Through the analysis of the relationship between the productivity and profitability, the primary goal of the study is to examine the factors that lead to the selection of a drilling pattern in a particular acreage.

1.2 Overview

Shale gas has changed the energy industry and the outlook of U.S. energy. With the ability to extract natural gas from resources previously thought to be technically and economically too challenging, U.S. natural gas production has rebounded. This has prompted an increasing amount of research on the effect of technology on shale gas. The Bureau of Economic Geology (BEG) at the University of Texas at Austin is performing a crucial investigation of future production scenarios of major U.S. shale plays. The BEG Shale study is conducting research on the Bakken and Eagle Ford shale oil plays, along with 4 major shale gas plays: Barnett, Fayetteville, Haynesville, and Marcellus. The project, supported by a competitive grant from by the Alfred P. Sloan Foundation, is an integrated study utilizing geology, engineering, and economics to model resource outlooks.

Assessment studies of U.S. shale gas have been conducted by the U.S. Energy Information Agency, EIA (EIA 2014a), U.S. Geologic Survey, USGS (Higley et al. 2014), and by industry (BP 2014). The BEG Sloan study differs in its approach to resource assessment by taking a bottom-up approach. The study uses production data from every producing well in a given play to generate a production profile to then apply this suite of production profiles to all current and future wells. Production decline is governed by a physics-based decline curve, which considers inter-fracture interference in its estimation, developed at the Department of Petroleum Geosystems and Engineering at the University of Texas at Austin. The fields are subdivided into production tiers depending on the region's geologic, engineering, and economic considerations. The outlook scenarios for each play are then projected based on a number of possible economic situations.

Many uncertainties exist about technological advances. Future production profiles and economic outlooks of a play can drastically change owing to technology. Additional attention regarding technology implementation is essential for future projections in any industry. This study provides further insights about how shale gas production outlooks may change thanks to alterations in drilling and completion techniques.

Motivation

In any production outlook, including EIA 2014 and Browning et al. 2014, key inputs include the number of drilling locations available for future drilling, their expected future productivity, and the economic value given the price of natural gas. As mentioned above, technologic advances may affect the values of listed inputs.

Recent studies on well spacing and drilling pattern, namely those focused on various types of cluster drilling, suggests operators are experimenting with closely spaced wells completed at lower per well cost that promises higher recovery. Higher recovery per stimulated rock volume is expected, but may not translate into higher per well recovery, due to the tighter spacing and overlapping drainage area. If cluster drilling becomes widespread in the play it may dramatically increase the estimations of future wells in the Fayetteville Shale.

The outcome in terms of economics is also not straightforward. Experimenting with well design can impact recovery factor and therefore have major implications on per well economics, a plays economic outlook, and profit margins. The consequences of using cluster drilling require further examination.

Objective

The study aims to evaluate the effect of cluster drilling on the productivity of shale gas wells, profitability, and attractiveness to further invest in the design. Focusing on the Fayetteville Shale, cluster drilling effects will be quantified by changes in well cost, gas production, and profitability.

The study sheds light on whether an operator will choose to use or not use cluster-drilling technology. These considerations can then be applied to other instances of new technology implementation.

Approach

A Fayetteville shale map showing wells drilled from 2005-2012 was used to visually isolate cluster and non-cluster wells. A group of cluster wells were selected for the study only if at least one non-cluster analog well was located within two miles of the cluster wells. Actual production history data was used to estimate the total recovery of the well over a 20-year life expectancy. The annual gas production was then input into a discounted cash flow model to estimate difference in cost, production, and profit of cluster and non-cluster wells.

1.3 Literature review

The nuances of shale gas drilling are just now being explored; furthermore each play has its own distinct characteristics that dictate a certain extraction technique. As such, there are many studies evaluating new technology or new implementation of technology and their effects on natural gas production and economics. This following literature review emphasizes a technological advance and the effects of its usage.

The question of well spacing comes down to economics. Roberts (1961) suggests that optimal well spacing is when wells are spaced less than the maximum drainage area of one well. In other words, the drainage area for two wells would be slightly over lapping. By overlapping drainage area, one could more quickly extract the resource. By more quickly extracting the resource the redundancy in well cost, in the form of overlapping drainage area, would be justified if the NPV of the two wells were greater than the NPV of not having them overlap.

Roberts (1961) is identifying well spacing and its effect on economics. From a different standpoint, changing well spacing can be viewed as a technological change or improvement. The natural gas industry is continually improving its technology to enhance productivity and economics, how new technology will influence well or lease profitability can have major implications.

In today's oil and gas industry a previously uneconomic source rock has recently become a viable resource, shale. Unlike conventional gas, shale gas cannot escape its reservoir once a well is drilled into the formation. The gas molecules are trapped within a tight shale matrix, which has a permeability of less than 1 millidarcy (Wang et al. 2014). In order to access and release the gas hydraulic fracturing of the reservoir is required. The hydraulic fracturing treatment can also be referred to as reservoir stimulation.

One way of enhancing productivity and or economics is to improve the fracture network created by fracking. The fracture network created by fracking is performed with explosive charges placed in strategic locations along the well bore. These charges can be placed in groupings called perforation clusters, not to be confused with cluster wells. Placement and spacing between these charges can positively affect the production in a shale gas well. Through reservoir simulation it was demonstrated that increasing the number of perforations does not guarantee better production (Cheng 2012). Each additional perforation requires an increased monetary investment. Instead of packing as many perforations into the well as possible, choosing the optimal perforation design will lead to better project economics (Cheng 2012).

Another example of technological innovation to improve productivity and profitability circles back to Roberts and well spacing. The importance of well placement cannot be stated strongly enough, each unconventional well costs millions of dollars. Ineffective or superfluous unconventional wells can turn a good project into a bad one. Sahai et al. (2011) demonstrate there is an optimal number of wells per area in a given shale play. Through reservoir simulation, they utilized various reservoir parameters and completion techniques to find an optimal well count per section in the Marcellus Shale. They conclude the Marcellus has an optimal well count of 5 wells per 640-acre section, an increase to up to 8 wells does not improve recovery factor. Not only do additional wells beyond the fifth well fail to improve recovery but they reduce the NPV of the 640 acre section (Sahai et al. 2011).

Finally an example of the technology effect in the Fayetteville shale is the use of percussion drilling. Not a new technique, percussion drilling is still being used in today's oil and gas industry (Ford et al. 2011). Percussion drilling does not require the same amount of drilling mud for circulation and rotary drilling, thus reducing costs. The increased drilling rate, reduction of drilling mud, and reducing the probability of lost circulation all add up to a lower drilling cost (Ford et al. 2011).

The low gas price environment has provided even more motivation for operators to find an optimal drilling formula. Improved fracture treatment, drilling tools, or optimal well count are just a few of the ways the oil and gas industry is trying to improve production and economics. Many studies, including those previously mentioned, have the goal of determining the outcome of technology on productivity. Some rely on reservoir simulation and others do not, but they all stress the importance of finding an optimal technique. What ties all these examples together is critical to understand. A technology used to improve performance or economics must be tailored to the specific play. Every shale play has its own unique geologic characteristics that will govern optimal drilling patterns and completion techniques. No single formula can be applied to all shale plays within the U.S. Play specific research and technology implementation will be essential for efficient and profitable shale gas extraction.

Chapter 2: History of U.S. Shale Gas and Fayetteville Shale

2.1 U.S. Shale Gas production

In 1998 the EIA reported U.S. energy consumption reached 94.0 quadrillion (quad) British thermal units (Btu), and projected energy growth would reach 118.6 quads in 2020 (EIA 1998). Petroleum products made up 38% of U.S. energy usage, natural gas was the next largest consumed fuel accounting for 24%, about 23 quads, of total energy consumption (EIA 1998). U.S. natural gas production only accounted for 18 quads, or ~20% of total U.S. energy consumption. Production in 1998 was at a slight increase but remained below the assumed peak production in 1973 (Figure 1).

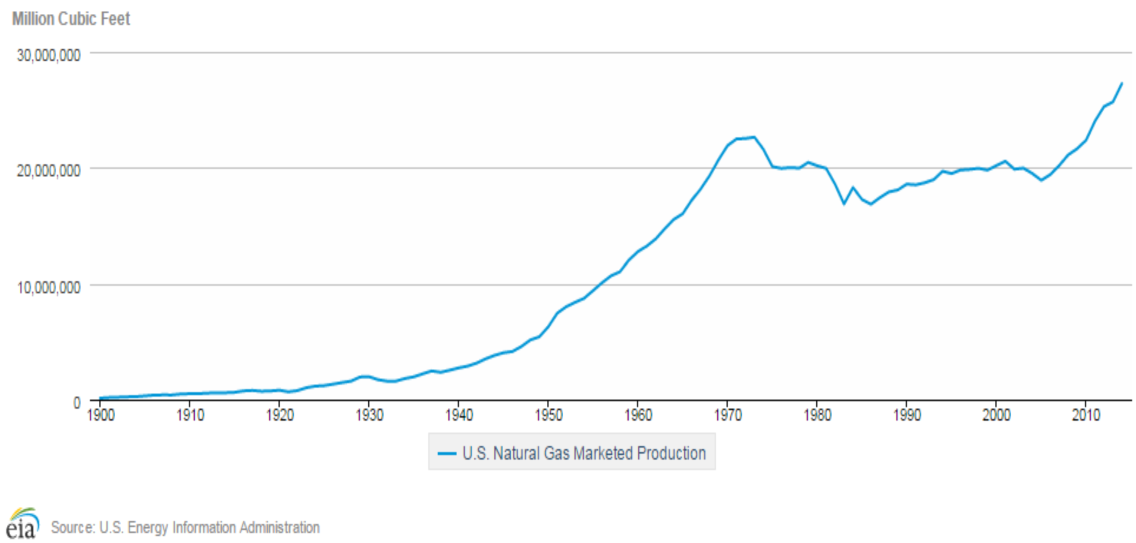

Figure 1 Annual U.S. natural gas production in million cubic feet (Mcf) (EIA 2015)

The gap in natural gas production and consumption was one of the reasons for concerns over U.S. dependency on foreign energy. Conventional natural gas resources were on the decline with no major discoveries on the horizon. With consumption continuing to rise, an increase in natural gas imports was inevitable. Liquefied natural gas (LNG) import projects began to form across the country, which would lead to major U.S. natural gas imports (Weijermars 2014).

The 1998 EIA projection of U.S. energy demand through 2020 did not hold true. EIA reports U.S. energy usage in 2012 was 94.5 quads (Dunn et al. 2015), which is lower than previously predicted due to efficiency, technological advances, and the effects of the 2009 recession. Natural gas usage has increased to 27% of total energy consumption and is projected to reach 30% of total consumption by 2040 (EIA 2014a). The gap in production and consumption had diminished, not widened, and instead of importing 1.5 Tcf of natural gas like in 2012, the U.S. is projected to export 5.8 Tcf in 2040 (EIA 2014a) (Figure 2).

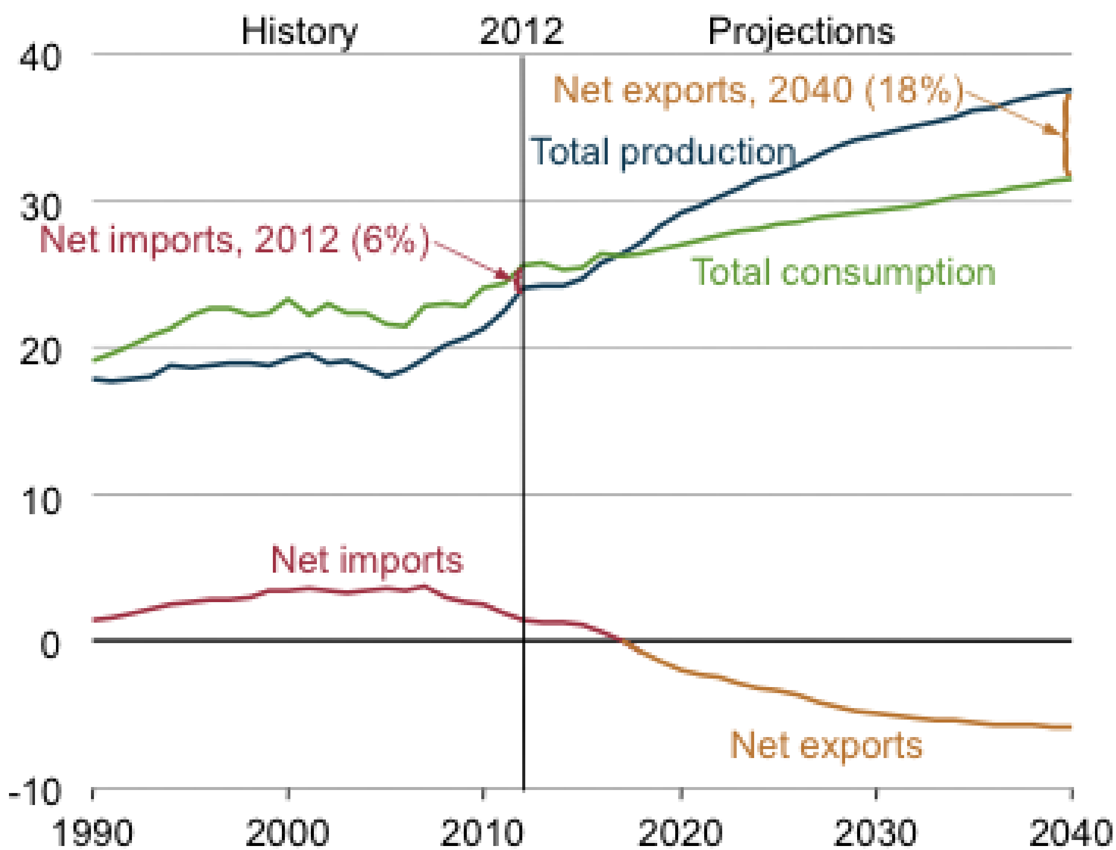

Figure 2. EIA Total U.S. natural gas production from 1990 to 2040 (Tcf) (EIA 2014a)

Shale gas production is the reason for this major shift in natural gas production outlook. In 2012 shale gas contributed 9.7 Tcf, or 40%, of total U.S. natural gas production, nearly 11% of total U.S. energy consumed (EIA 2014a). That is up from negligible contributions in the late 1990s early 2000s. Shale gas has seen the largest production growth compared to any other source of natural gas and any other source of energy in that time period (Figure 3) (EIA 2014a).

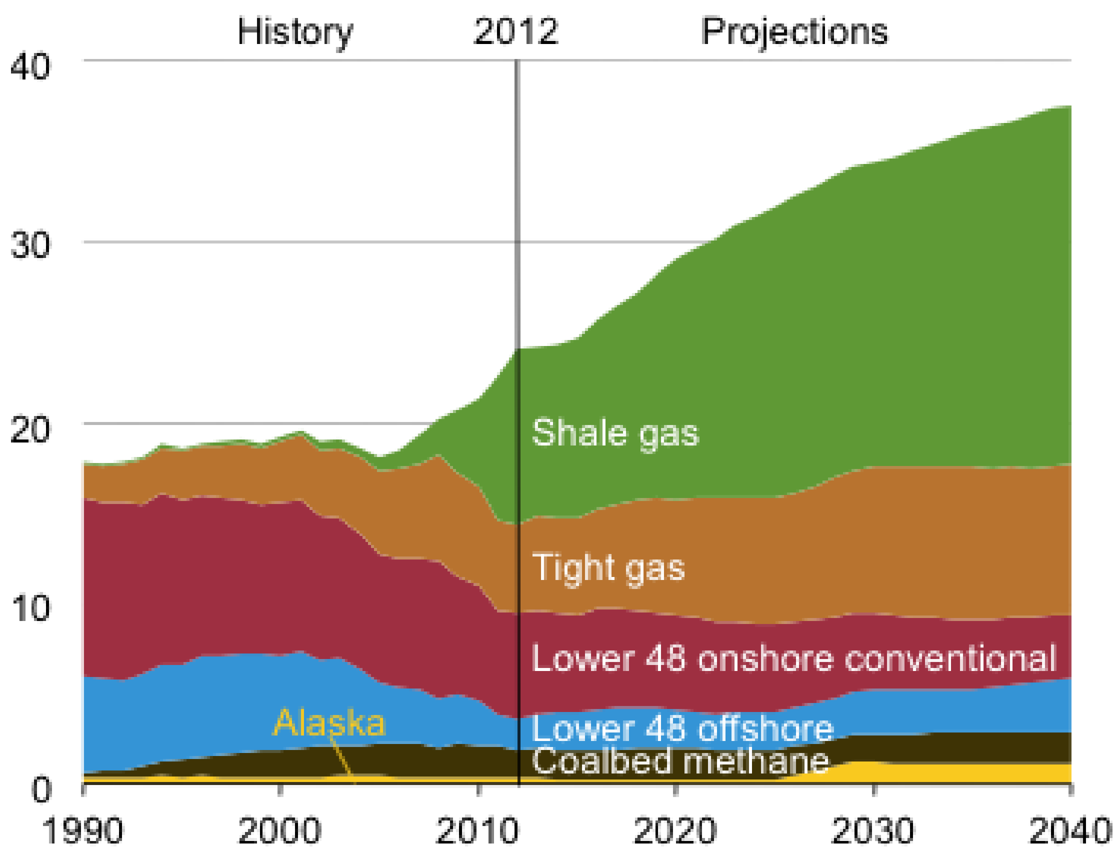

Figure 3. EIA 2014 Annual U.S. natural gas production by source, 1990-2040 (Tcf) (EIA 2014a)

Although BEG future scenarios are more conservative, EIA (2014a) projections show shale gas making even larger contributions to natural gas production in the future, as much as 53% of U.S. production could be from shale gas. As shale plays across the country continue to be drilled, shale gas production will only increase the prospect of U.S. natural gas independence.

2.2: Fayetteville Shale: The study area

The Fayetteville Shale has become a significant contributor to U.S. shale gas production. The Fayetteville Shale has continued to increase its production, making Arkansas the fourth-largest shale gas producing state in the U.S. (EIA 2014b). In 2013 the Fayetteville shale produced about 2.8 Bcf/day or about 9% of total U.S. shale gas production (EIA 2014b) (Figure 4).

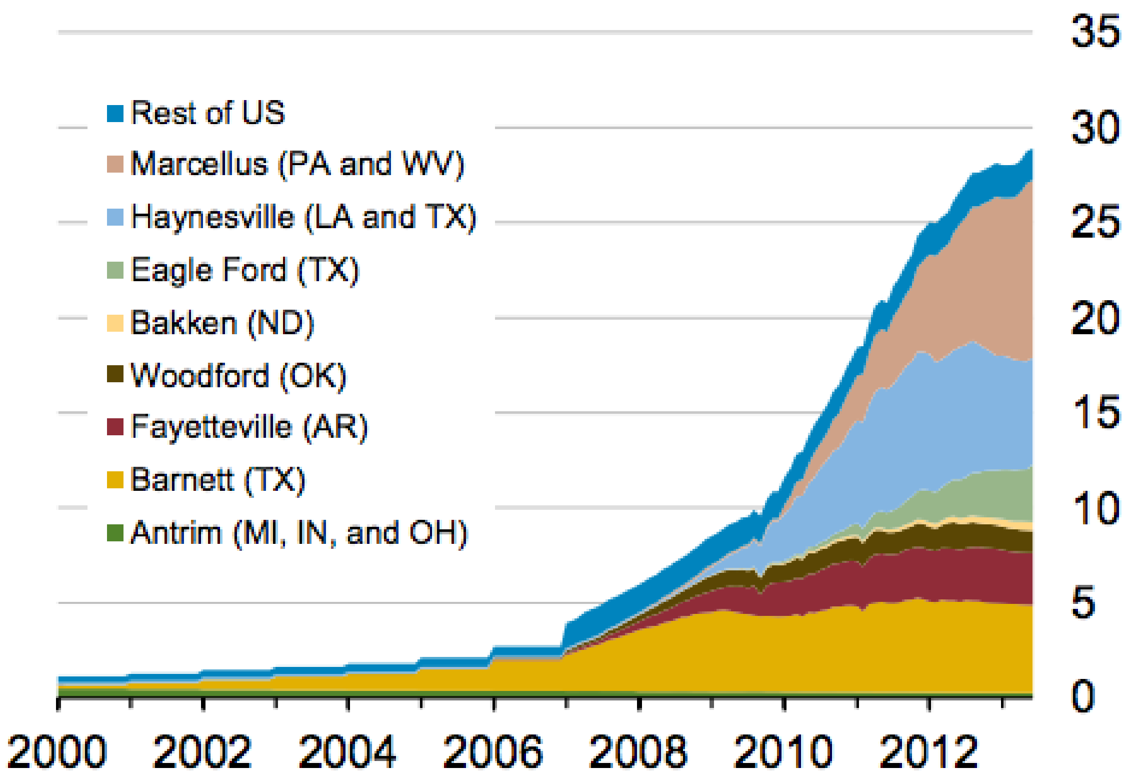

Figure 4. U.S shale dry gas production in Bcf/day (Sieminski 2014)

The Fayetteville shale, part of the Arkoma Basin, is a Mississippian-aged shale gas formation located in North Central Arkansas (Figure 5). The formation's age is geologically equivalent to the Barnett Shale found in North Texas (Harpel et al. 2012). The formation has a depth ranging from 1,500 to 8,000 feet and gross thickness ranging from 50 to 550+ feet (Browning et al. 2014, Harpel et al. 2012). The study area covers approximately 2,737 square miles in the formation.

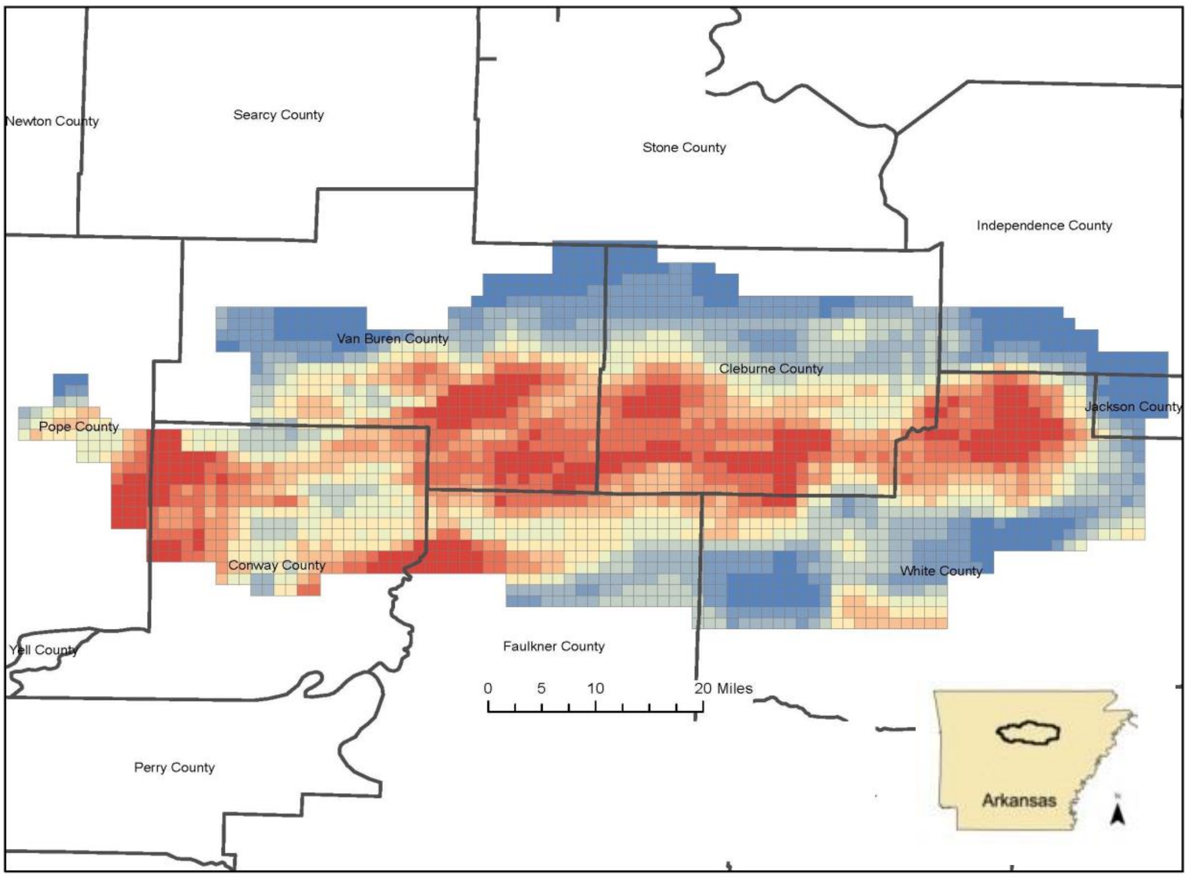

Figure 5 Study Area: Fayetteville Shale play located in North Central Arkansas (Ikonnikova et al. 2015)

The Fayetteville shale is a dry gas play, with the original free gas in place ($OGIP^{free}$) estimated to be about 80 Tcf (Browning et al. 2014). The $OGIP^{free}$ is the total amount of natural gas estimated to be in a reservoir prior to drilling activities (McGlade et al. 2013) and net of sorbed gas (Ikonnikova et al. 2014). The amount of gas that can be extracted from the reservoir with known technology is called technically recoverable gas. Of the 80Tcf in the Fayetteville Shale said to be free gas in place, approximately 16.9 Tcf is calculated to be technically recoverable (Gulen et al. 2014). Because technology is continually improving, technically recoverable gas also increases.

Development history

At the moment, Southwestern Energy is the primary operator in the Fayetteville Shale, with leases covering two thirds of the play. The company has a long history in Arkansas, establishing as Arkansas Western Gas Company (AWG) in 1929. After years of natural gas production and distribution, AWG changed its name to Southwestern Energy (SWN) in the 1980s. After the breakthrough in horizontal drilling and hydraulic fracturing in the Barnet Shale play, SWN made its first purchase of undeveloped acreage of Fayetteville Shale in 2003. In 2004 SWN accumulated 575,000 net acres in the Fayetteville Shale. Southwestern quickly developed the play production to 100 MMcf per day in 2006, 500 MMcf per day in 2008, to over 2 Bcf per day in 2012 (Southwestern Energy, 2015a). Southwestern acquired additional acreage in 2010 and as of year-end in 2010 held 916,000 net acres (Harpel et al. 2012). The play has produced over 3.0 Tcf since its first well in 2004 (Southwestern Energy, 2015b).

Just as SWN has increased its holdings and production over time, since their first well in 2004, SWN has continually improved their drilling operations. In 2007 it took 17.5 days to drill and complete a well about 2,600 feet in horizontal length (Burgess & Sartoretto 2014). By 2011 days to completion only took 7.9 days for a well approximately 4,800 feet in horizontal length (Burgess & Sartoretto 2014). Predictably their production per year continued to grow as well, from 54 Bcf in 2007 to 437 Bcf in 2011(Burgess & Sartoretto 2014).

As SWN's timeline for drilling operations and total production continued to improve, the gas recovery (EUR) per length of well drilled remained relatively similar (Figure 6). Without knowing how SWN changed their completion techniques over the years it is difficult to determine exactly how their completions have been optimized. However, evaluating the estimated ultimate recovery (EUR) of gas per length of well, one can infer a change in completion technique. In 2009 the deviation in recovery per length began to decrease, possibly signifying technology plateau.

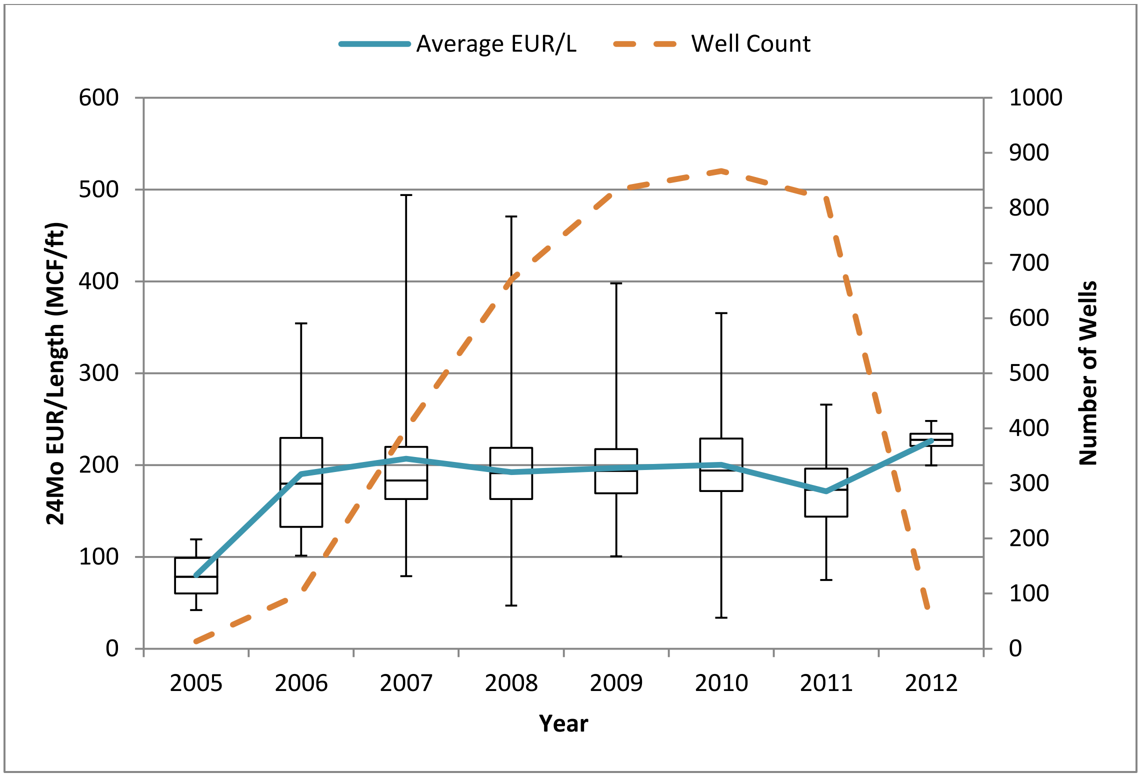

Figure 6 Estimated ultimate recovery per length and number of wells drilled from 2005 to 2012

Just as their completion technique seemed to be solidified, around 2010 a very tight drilling pattern, cluster drilling, began to emerge. This cluster-drilling pattern coincides with SWN's use of pad drilling operations (Harpel et al. 2012). In some areas three non-cluster wells were drilled and a year later four or five cluster wells were squeezed together covering a similar surface area. Tighter spacing could be utilized to optimize completion techniques like implementation of zipper fracking. Zipper fracking is a technique where two parallel horizontal wells are simultaneously stimulated. By using this technique the fractures are designed to propagate toward one another to allow better rock stimulation (Rafiee et al. 2012). SWN may have implemented tighter spacing in order to increase production in the field, hence the increasing presence of the tight cluster-drilling pattern.

Chapter 3: Analysis

3.1 Previous work

This study follows the previous work of Browning et al. 2013 in the Barnet Shale, Gulen et al. 2014 and Ikonnikova et al. 2014 in the Fayetteville Shale. The Barnett study was the first published work in the series and provided production and future reserve scenarios based on geologic, engineering and economic considerations. In these studies the approach was based on production history from the play and considered the remaining undrilled areas as a function of production potential and economic scenarios (Browning et al. 2013). The analyses emphasized a physics-based decline model and a discounted cash flow economic model which were foundational pieces for later work in the Fayetteville shale.

This study also uses production data obtained from IHS and DrillingInfo including well location, drilling path, and monthly production. Almost 4000 horizontal wells were used by Male et al. in revision, to generate a typical production profile for all wells in the play. Aside from a modification to production decline in years 2-4, this study incorporates the EUR estimation method used in previous BEG Fayetteville studies (Browning et al. 2014, Gulen et al. 2014, Male et al. in revision).

3.2 Well Selection

According to SWN, as of December 31, 2013 they had drilled a total of 4,110 wells since 2004 (Southwestern Energy 2015a). Based on the results of Ikonnikova et al. (2015), SWN investor presentations, and visual examination of the map, only wells drilled from 2009-2011 were chosen for this study. During that time, average horizontal well lengths were 4,100-4,800 feet (Burgess & Sartoretto 2014). Wells chosen for the study were categorized as cluster or non-cluster wells. Cluster wells are defined as a tight grouping of wells drilled and completed at the same time. Non-cluster wells were often drilled as a single well or a group of two to three wells spaced further apart than cluster wells (Figure 7).

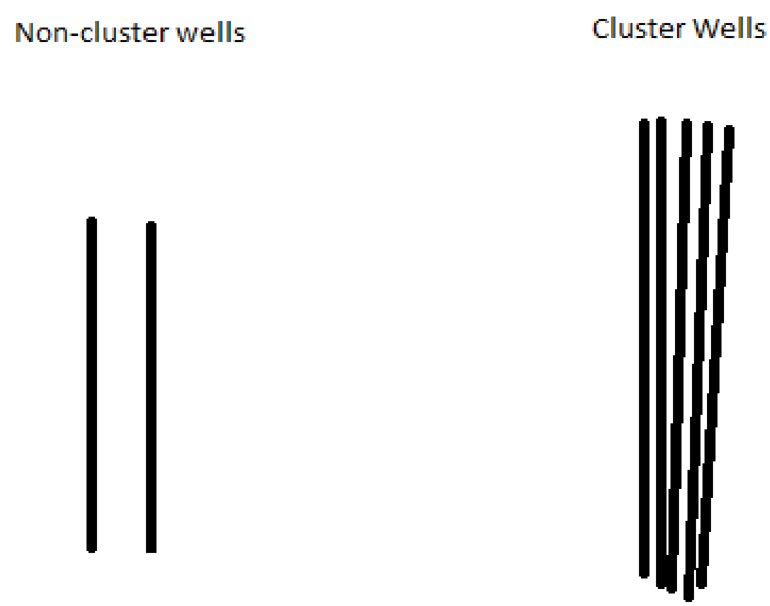

Figure 7 An example of non-cluster and cluster wells in the Fayetteville Shale (modified from the actual wells)

To perform a comparison of cluster and non-cluster wells the study considered well length and proximity. As discussed in chapter 3 section 1, the Fayetteville Shale can vary in thickness and depth across the play. Not only can the volume of reservoir vary depending on location, but geologic heterogeneities vary greatly across the field. Even within a few square miles geologic heterogeneities can be significant. Thus, some frack stages are better than others within a single well. Given this variability, the study attempts nonetheless to compare wells in close proximity and as similar as possible. The assumption is that closer wells are more likely to be producing from intervals with similar geologic properties and gas in place values.

Once a set of cluster wells was identified, a similar length analog non-cluster well(s) were chosen in close proximity, less than 2 miles away. A total of 353 cluster wells and 213 non-cluster wells comprise the database for this analysis (Figure 8). The majority of cluster wells were drilled in a grouping of three wells and often the analog non-cluster well was a single non-cluster well. The database does not attempt to hold constant the volume of stimulated rock. This aspect of cluster and non-cluster well comparison can be investigated in future research.

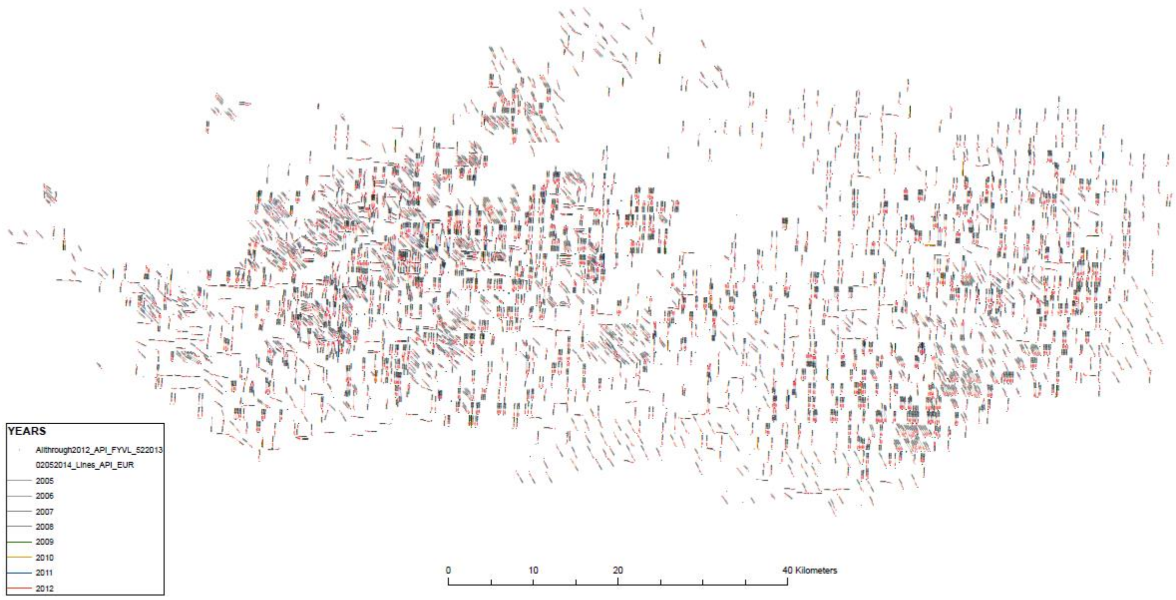

Figure 8 A map of wells drilled in the Fayetteville Shale from 2005-2012

3.3 MODELING APPROACH

Production Decline

When building a well economics model there are many factors that contribute to the final outcome scenarios. One of the most important engineering considerations is decline curve analysis. Decline curve analysis is the method of estimating the rate of production reduction for a given well. It can be used with the production profile of an average well in a play to project the EUR over the life of the well.

While there are different types of decline curves, this study employed a physics-based model for low permeability shale gas used in the Fayetteville Shale-Production Outlook study which is based on previous work in the Barnett Shale (Patzek et al. 2013).

The decline curve follows transient linear flow for an individual well declining at $\frac{1}{\sqrt{(\text{time})}}$ for the first few years of production (Patzek et al. 2013). After three to five years interfracture interference reduces pressure between hydrofractures, causing the wells' production to decrease exponentially (Patzek et al. 2013).

Estimating EUR

After selecting the desired wells, the economic model required an estimate of well life production to evaluate profitability. Projecting the estimated ultimate recovery (EUR) required a wells initial production and a production profile (Figure 9). The wells vary in age so they have a different number of data points. In order to compare these wells over a similar period in production history the first twelve months of cumulative production was chosen to represent a well's initial production (q_0).

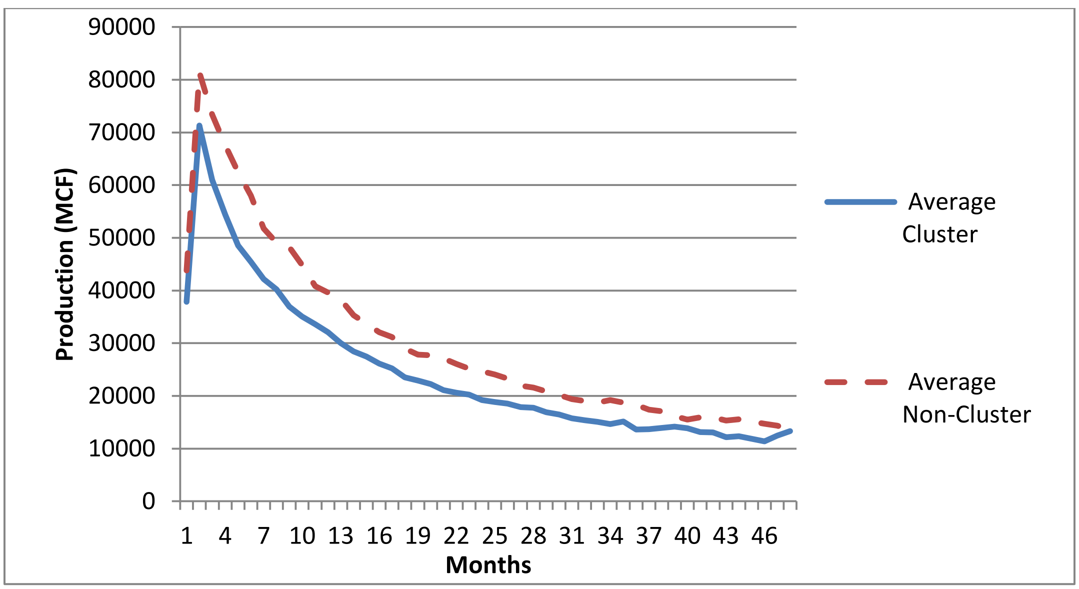

Figure 9 Typical production profiles for the first 4 years of the average cluster and non-cluster wells

This study uses the same 20-year production profile as the Ikonnikova et al. (2015) study with modification to the production decline in years 2-4. For this study production decline will be represented as the production ratio relative to q_0. The rates of production for years 2-4 were determined with historical production data and are represented by the term alpha (α). Alpha values for every cluster well were averaged to generate typical cluster production ratios for years 2-4 (α_1, α_2, α_3). Non-cluster wells were manipulated in the same manner.

Alpha (α) is the production ratio relative to q0 and calculated as follows:

$$\alpha_1 = \frac{q_1}{q_0} \qquad \alpha_2 = \frac{q_2}{q_0} \qquad \alpha_3 = \frac{q_3}{q_0}$$

q_0= 1-12 month cumulative production

q_1= 13-24 month cumulative production

q_2= 25-36 month cumulative production

q_3= 37-48 month cumulative production

DCF Model

Production over time is the input for a discounted cash flow model (DFC) to determine a well's value. A DFC has been used by Ikonnikova et al. (2014) and Gulen et al. (2014) to estimate and compare the economics of shale gas wells within a play. A few economic factors need to be considered, including:

- Drilling-Capital-Expenditure
- Well Expense/year
- Royalty Rate
- Severance Tax Rate,
- Inflation Rate
- Economic Limit
- Waste disposal Costs
- Abandonment Costs
- Lease Cost/acre
- Well Spacing

Using these economic factors the DFC uses future free cash flow projections, along with the discount rate (DR or r), to project the present value of a project completed in the future. The sum of all the free cash flows is the net present value (NPV), which can be considered the monetary value of the project today. Economic value indicators can be produced from the DFC. For this study the focus will be on the net present value (NPV), breakeven price (BE), internal rate of return (IRR), and the present value index (PVI).

Economic Indicators

NPV: Net Present Value

NPV is the present value of total incoming and outgoing cash over a given period of time. Traditionally the formula for NPV is as follows (Ikonnikova et al. 2015):

$$NPV = \sum_{t=1}^{T} \frac{C_t}{(1+r)^t} - C_o \qquad (1)$$

Ct= net cash flow in given time

Co= initial capital investment

r= discount rate

t=number of time periods.

For shale gas drilling the initial capital investment will be drilling and completion costs, referred to as drilling capital expenditure, drilling capex or DC. The net cash flow in the given time will be composed of shale gas revenue R_t, operating costs OC, and income tax (IT). Equation (1) can been rewritten as equation (2) (Ikonnikova et al. 2015):

$$NPV = -DC + \sum_{t=0}^{T} \frac{R_t - IT_t - OC}{(1+r)^t} \qquad (2)$$

One important parameter affecting NPV is the discount rate (DR or r). The DR is the interest rate applied to future cash flows in a DCF. The cash flow five or ten years after the start of a project has a lower value than the cash initially used to invest in the project. The DR is used to consider the time value, risk, or uncertainty of future cash flows invested or generated from the project. The use of a high DR indicates the operator requires more return for the usage time of their capital, believes the project has more risk, or that the future cost of money will be high.

NPV serves to calculate the absolute investment profit of a project over the life of the project. The NPV is often used as an indicator of a good or bad project. In simple terms, if the NPV is positive the project is good while a negative NPV represents a bad project. NPV can also be used to derive other economic indicators such as PVI.

BE: Breakeven Price

The breakeven price is the amount of money the product of a project must be sold for to cover the cost of doing the project. In other words, it is the price the product is sold for that equates to the NPV of the project, given a certain discount rate, becoming zero. In this case the breakeven price is the gas price the natural gas is sold for that equates to the NPV, given a certain discount rate, of a well becoming zero. From an operator perspective, if the produced gas over the life of the well was sold at its breakeven price they would recover all the money invested into the well over the entire life of the well but make no profit.

IRR: Internal Rate of Return

An indicator of how valuable a project, or in this case a well, can be is the IRR. IRR is the discount rate in which the NPV of a project is zero. IRRs can be compared to one another if all other variables of a project are equal, then the project with the highest IRR would be the most desirable project. What makes that comparison difficult is the need for all other variables to be the same. This problem makes comparing the IRRs of two different types of wells, cluster or non-cluster wells, far from ideal.

PVI: Present Value Index

Both NPV and IRR are important indicators of project economics and decisions making but they both falter in one aspect, scaling. The NPV or IRR of two different projects may be similar but what is not captured in the comparison is the initial investment required by the two different projects. The present value index (PVI) is a value indicator that addresses that problem. It can be used to compare projects with different initial investments because it measures the net gain received from every dollar initially invested (Mian, 2011). The ratio compares project NPV to the initial investment required to start the project. The PVI is calculated as follows:

$$PVI = \frac{NPV}{Initial\ Investment}$$

The PVI can be used to evaluate two different projects with different drilling costs, like a lease with one non-cluster well to a lease with two cluster wells. In that scenario, the project with the higher PVI indicates that project gained more NPV per dollar initially invested, and is thus a more monetarily efficient investment. For this study the initial investment is the drilling capex and the PVI equation can be rewritten as:

$$PVI = \frac{NPV}{Drilling\ Capex}$$

It is important to note that a change in the PVI value can be from either project NPV or the initial investment. If a project stays exactly the same but the material used to build a well experiences a reduction in cost the PVI will increase. Without looking into a discounted cash flow model (DFC), specifically the economic parameters that effect NPV or DC, what prompted a change in PVI may not be obvious.

3.4 Economic Parameters

To model the effect of cluster drilling technology on well profitability, an adaptation of the model used in Gulen et al. (2014) and Ikonnikova et al. (2014) was used. The model allows for evaluation of any number of wells drilled within a certain acreage, it tests the effect changes to production or cost have on well economics. The NPV indicator is calculated for every discount value from 0-20% in increments of 2%, but the study focuses results based on a discount rate of 10%. The PVI values reported in the study are also based on an assumption of the operator using a 10% discount rate for the well(s) in question. The key assumptions for non-cluster drilling are found in Table 1.

Drilling cost (CAPEX)	$3,000,000	Severance tax rate	5% or 1.5%
Royalty rate	15%	Lease cost/acre	$1,200
HH Real	$4.00	Spacing (acres)	70
Economic Limit (MMcf/d)	0.03	Marginal tax rate	35%
Expense/well/yr	$25,000	Abandonment	$75,000
Capex reduction for cluster wells	25%	Inflation rate	2.5%

Table 1 Key assumptions for economic modeling.

Most of the assumptions for non-cluster drilling in Table 1 are the same for cluster drilling. Since cluster drilled wells are drilled from a single pad there are a few benefits that will alter the cost of a well. First, cluster wells are drilled much closer than non-cluster wells, for this study cluster well evaluation is based on spacing half the distance of non-cluster well spacing. This is consistent with the decrease in well spacing from the standard design of 600 feet to 400 and 300 feet reported from SWN (Harpel et al. 2012). The reduction in spacing will affect the cost of the lease; cluster wells have a lower lease cost per well. Second, and most important, cluster drilling reduced the amount of drilling capex. Multi-well pad drilling and zipper fracking equates to a reduction in equipment rental time, drilling time, water and sand usage, and surface impact. The combined benefits to reduction of drilling time and cost from cluster drilling from single pad locations have been demonstrated in the East Kalimantan gas field, reduction to well costs can be upwards of 20% (Hazman et al. 2008).

This section has described just a few of the many factors, in either production or economics, which are used in projecting the outlook of shale gas wells. Projecting shale gas production and decline is extremely difficult and the method used in this study has yet to be proven with historical data but is essential in providing as accurate as possible EURs. Those EURs can then be used to project a variety of economic indicators from a DFC. How an operator chooses to use or interpret the results of the DCF can affect the approach and outlook of a particular acreage or lease.

Chapter 4: Results and Discussion

The results from the analysis are structured in order of what was required to determine well economics and profitability. First, initial production values of both classes of wells were calculated and compared. Then production decline for cluster and non-cluster wells were calculated by year over the first four years of production. Combining these two portions of production analysis with the profiles generated by Male et al. (in revision) provided the EURs need to input into the DFC. Only then could the economic indicators, BE, NPV, IRR, PVI, be calculated and compared. Finally, two lease examples highlight the results found in the analysis of cluster drilling on shale gas production and profitability.

4.1 Initial Production

A look at initial production, $q_{0,}$ is the first piece of information that can reveal a difference in production, and eventually EUR, for cluster and non-cluster wells. The study identified 124 cluster and non-cluster complexes. On a per well basis, 56% of the complexes show the non-cluster well(s) outperforming the cluster wells in gas recovery. Cluster wells had an average initial production (q_0) of 536,279 MCF with a median of 515,419 MCF. Non-cluster wells q_0 had an average initial production of 650,984 MCF with a median of 637,418 (Figure 10).

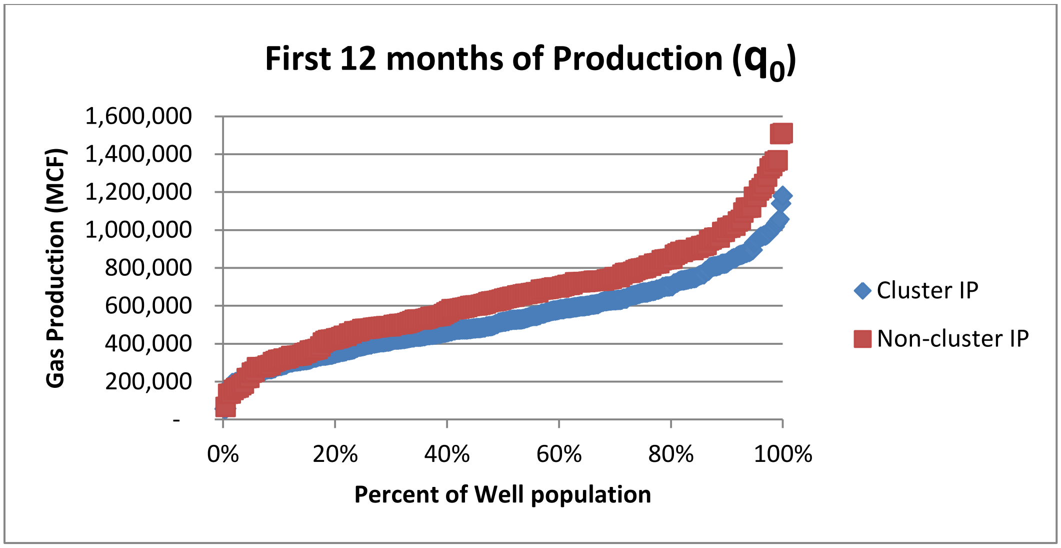

Figure 10 Distribution of cluster and non-cluster well initial production (first 12 months)

The difference in average cluster and non-cluster q_0 is 18%. While a difference in q_0 was expected due to tighter well spacing, the effect of diminished cluster q_0 per well can only be clarified with production decline and EUR estimates.

4.2 Production decline

The α_1 production ratio describes the average ratio of natural gas recovered in year two, months 13-24, relative to q_0. The α_1 ratios of cluster and non-cluster wells were compared to determine if the two classes of wells experienced differences in production decline over time. The results show that after the first two years of production cluster wells begin to experience a faster production decline than non-cluster wells.

Both cluster and non-cluster well α_1 values were fairly normally distributed (Figure 11). The average non-cluster α_1 was 0.54 slightly higher than cluster α_1 at 0.52.

Cluster and non-cluster well α_1 values show nearly identical production distribution (Figure 12). Interestingly, cluster well decline was not more prevalent in year two. In the second year of production non-cluster wells produced 4% more q_0 than cluster wells. Aside from the difference in q_0, cluster and non-cluster well behavior in their first twenty four months of production are relatively the same. Although production profiles over the first two years are similar, a lower average q_0 with a 4% faster decline results in even lower per well recovery for cluster wells in year two.

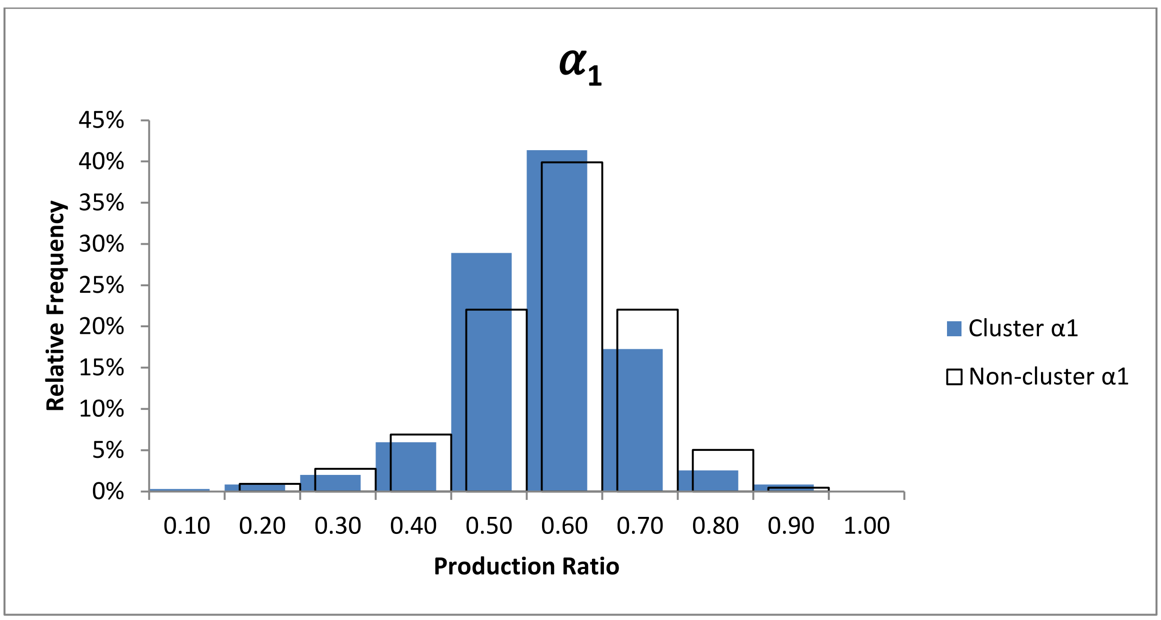

Figure 11 α_1 year 2 production ratio of cluster and non-cluster wells

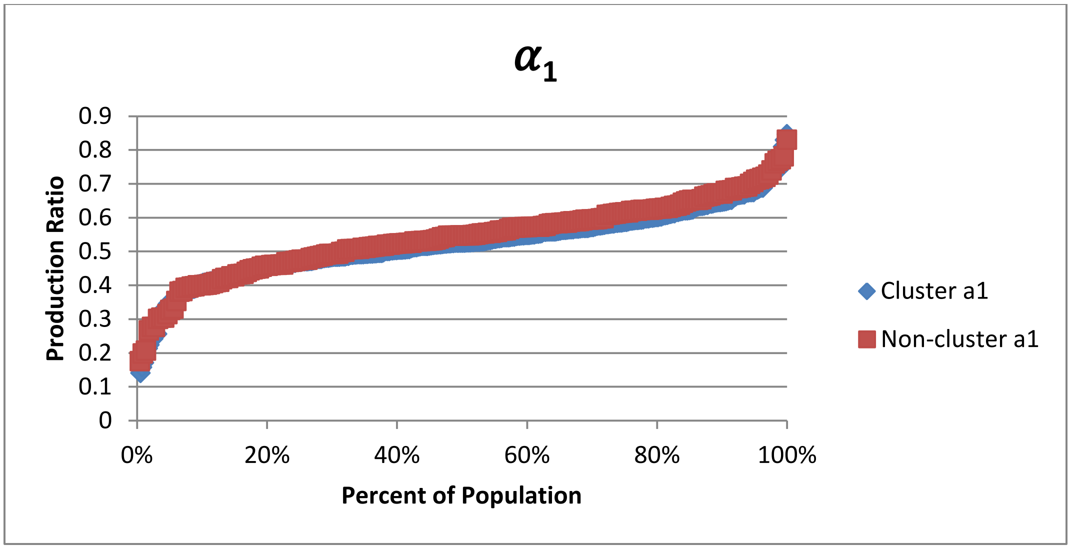

Figure 12 Distribution of α_1 year 2 production ratios

Year three is when the rate of decline really begins to deviate between cluster and non-cluster as shown by the gap between the production ratios of the well types (Figure13) and the cluster α_2 shifting left toward lower production ratios (Figure 14).

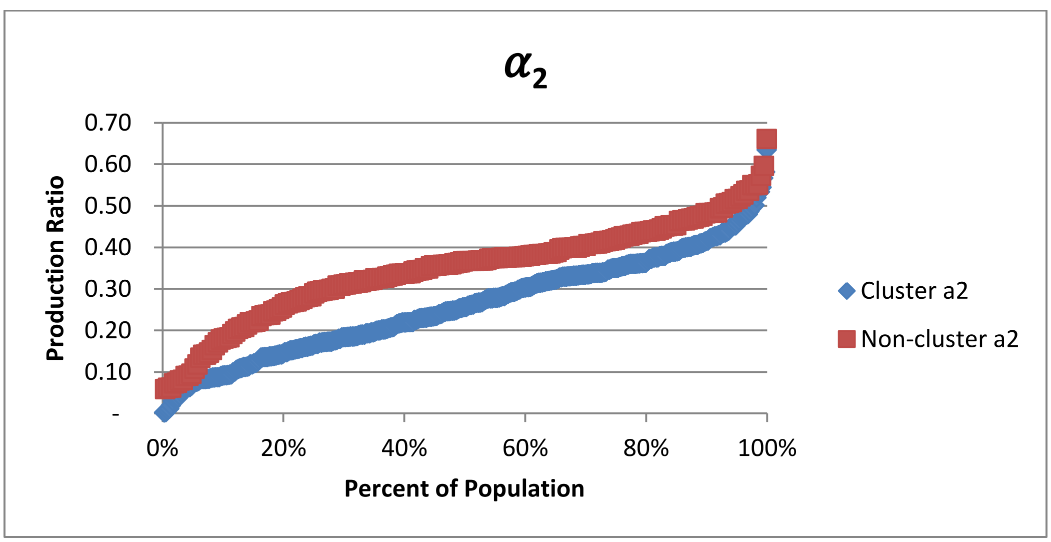

Figure 13 Distribution of α_2 year 3 production ratios

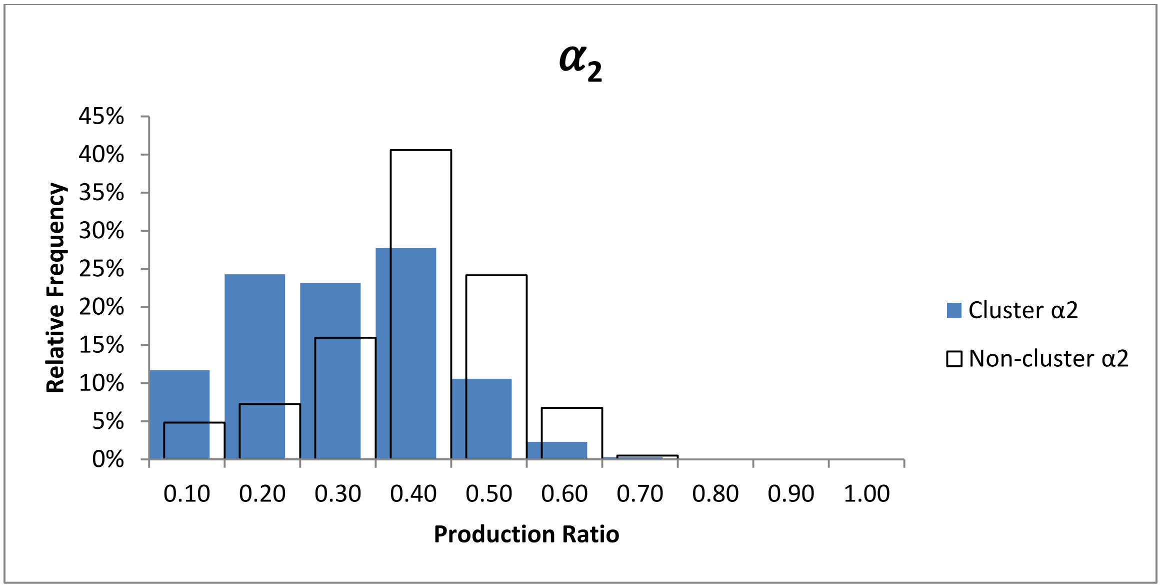

Figure 14 Relative frequency of α_2 year 3 production ratios

α_2 shows the steeper production decline in cluster wells. Non-cluster wells produced 34% of the q_0 gas, and clusters produced 26% of q_0 gas. The difference in production from clusters to non-cluster wells has grown from just 4% in year 2 to 24% in year 3.

The final decline ratio based on historical production data, α_3, continues the downward trend for cluster wells (Figure 15). The gap between the production ratios has continued to grow (Figure 16).The difference in α_3 is 39%, average non-cluster α_3 is 0.24 while cluster α_3 is 0.14. While the gap in decline has gotten larger, the rate of that change has slowed down. As the wells age and move toward their end of life, their rates of decline will merge to a singluar value.

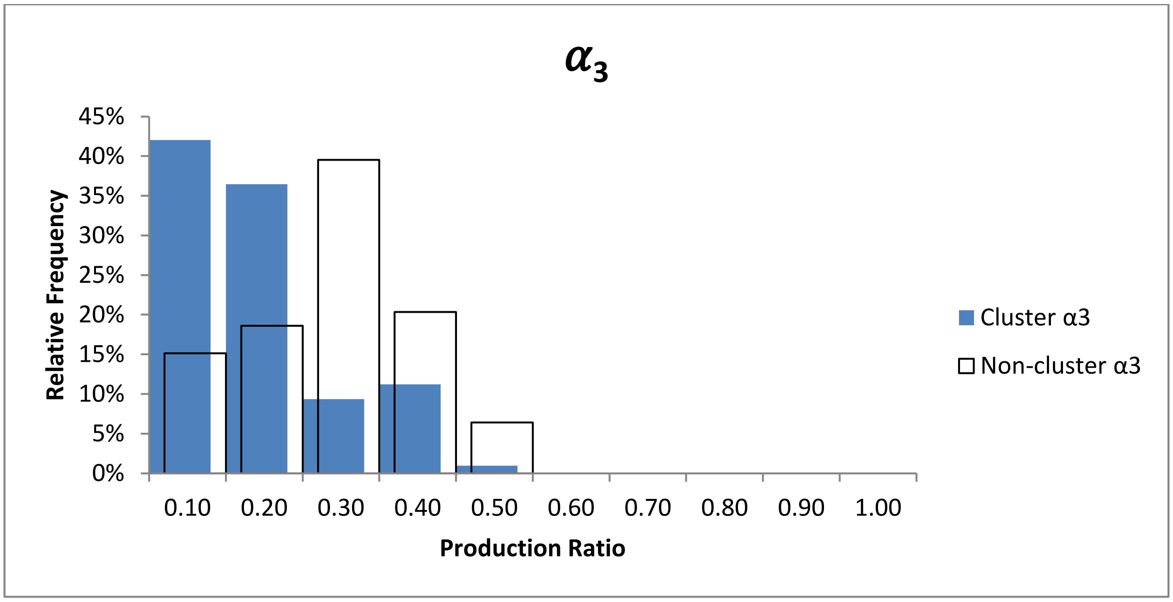

Figure 15 Relative frequency of α_3 year 4 production ratios

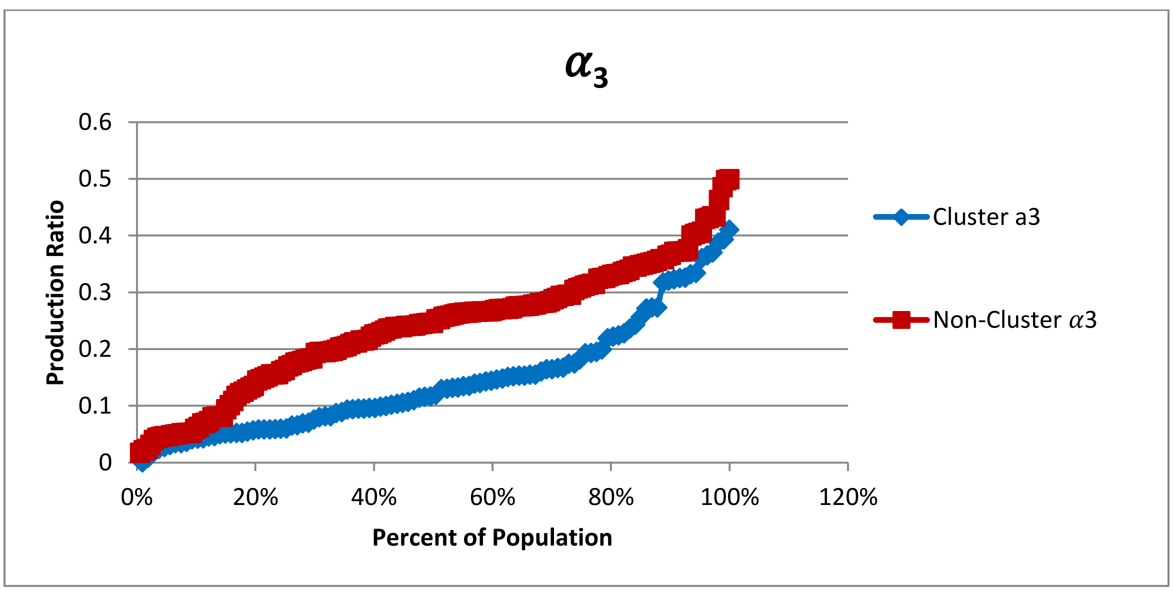

Figure 16 Distribution of α_3 year 4 production ratios

As a result of starting with a lower initial production as well as experiencing faster production decline, the average cluster well will see a 25% reduction in shale gas recovery (EUR). A non-cluster well will have an EUR of 2.5 Bcf while a cluster well will have a 1.9 Bcf EUR over a 20 year well life expectancy (Table 2).

	Average q_0(MCF)	Average α_1	Average α_2	Average α_3	Average EUR per well (MCF)
Cluster	536,279	0.52	0.26	0.14	1,868,480
Non-Cluster	650,984	0.54	0.34	0.24	2,477,650
Difference	18%	4%	24%	39%	25%

Table 2 Production and production ratios for the average cluster and non-cluster well

Cluster wells having lower gas extraction also mean lower gas sale and possibly a reduction in per well profit for cluster wells compared to non-cluster wells. Analyzing well economics with a DFC will determine just how much the reduction in production will affect profitability.

4.3 Well Economics

The well economics results demonstrate the difference in profitability of cluster and non-cluster wells. The two classes of wells show distinct economic benefits that an operator will need to consider when making a decision. As a preview, usage of the cluster well pattern will lead to higher NPV and higher gas recovery factor per lease. Non-cluster drilling lends to better monetary value for the investment. This will be shown in the following section starting with breakeven prices, well cost, NPV, IRR, and PVI.

Breakeven prices were calculated to evaluate the economic difference between cluster and non-cluster wells. The first comparison of breakeven prices considers non-cluster and cluster wells to both have an initial drilling capex of $3 million. In this scenario non-cluster wells have significantly lower breakeven prices for discount rates from 0-20% (Table 3). At 10% DR a non-cluster well requires $3.60/mmBtu over the 20-year life of the well to breakeven. Cluster wells with the same average well cost of $3 million and a 10% DR would needed a minimum natural gas price of $4.42 to breakeven (Table 3). The 22%-23% increase in gas price required for cluster wells signifies, for any given price, cluster wells would not be as profitable as non-cluster wells.

Discount Rate	Non-cluster breakeven price for given Discount Rate	Cluster breakeven price for given DR no Capex reduction	Absolute difference of non-cluster and cluster BE	Percent difference (increase) in Cluster BE price
0%	$2.94	$3.58	$0.64	22%
2%	$3.07	$3.75	$0.68	22%
4%	$3.21	$3.93	$0.72	22%
6%	$3.34	$4.10	$0.76	23%
8%	$3.47	$4.26	$0.79	23%
10%	$3.60	$4.42	$0.82	23%
12%	$3.72	$4.58	$0.85	23%
14%	$3.84	$4.72	$0.88	23%
16%	$3.95	$4.86	$0.91	23%
18%	$4.06	$4.99	$0.93	23%
20%	$4.16	$5.12	$0.95	23%

Table 3 Breakeven prices for cluster and non-cluster wells for a given discount rate with both well types starting with $3 million drilling capex

To this point, cluster drilling has already proven to recover less gas per well, thus requiring significantly higher gas prices to compete with non-cluster wells. Because many operators utilize the cluster-drilling pattern, we tested for other kinds of benefits that would to make the investment worthwhile. As previously discussed, one benefit is a reduction in drilling capex. To test the amount of reduction to cluster drilling cost is needed, the percent of cluster capex reduction required to match non-cluster breakeven prices were calculated. The results (Table 4) show the need for cluster wells to reduce their drilling capex by 22-33%. By choosing a certain DR, one can see the non-cluster breakeven price with the dotted line and the percent of reduction in cluster drilling capex with the solid line (Figure 17).

Discount Rate	Non-cluster well breakeven price for given DR	New individual Cluster well capex needed to match non-cluster BE	Percent of capex reduction from 3M
0%	$2.94	$1,975,296	33%
2%	$3.07	$2,023,889	31%
4%	$3.21	$2,060,353	26%
6%	$3.34	$2,088,628	25%
8%	$3.47	$2,111,310	24%
10%	$3.60	$2,130,120	24%
12%	$3.72	$2,146,208	23%
14%	$3.84	$2,160,341	23%
16%	$3.95	$2,173,038	22%
18%	$4.06	$2,184,648	22%
20%	$4.16	$2,195,408	22%

Table 4 Reduction in drilling capex for cluster wells to match breakeven prices for non-cluster wells.

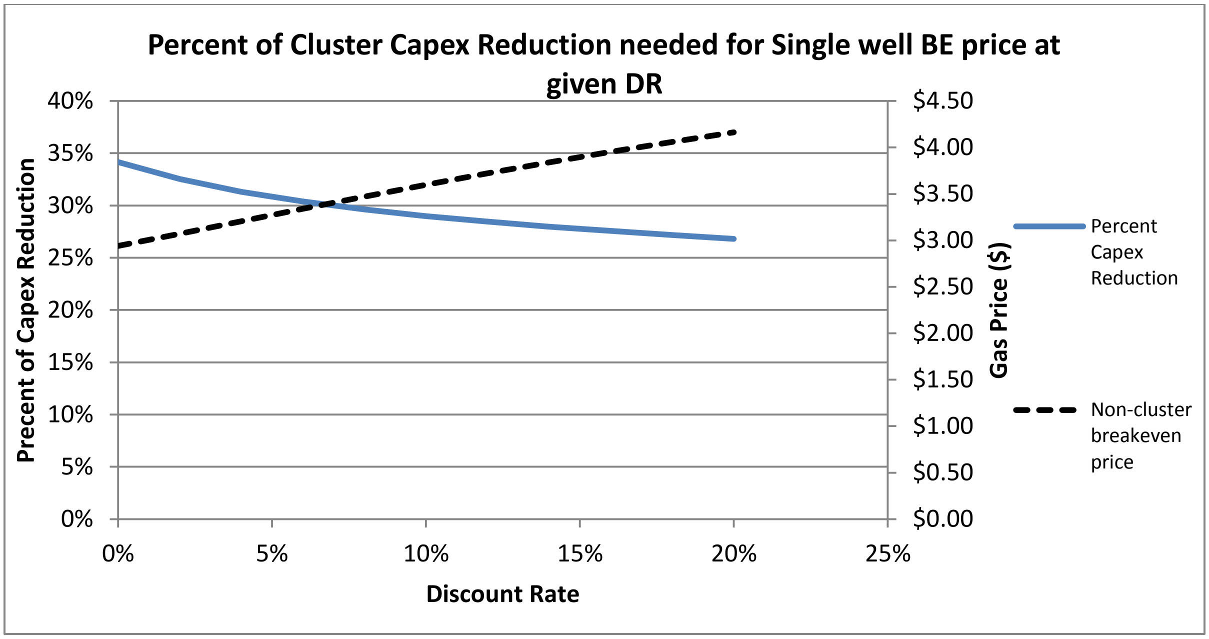

Figure 17 The percentage of capex reduction required for a cluster well to match non-cluster breakeven price at a given discount rate.

Breakeven prices were then recalculated using a 25% reduction in drilling capex. The 25% reduction provided immense benefit to cluster well economics; breakeven prices were much closer to their non-cluster counterparts (Table 5). The cluster breakeven price at 10% DR was reduced to $3.68 from $4.42 when there was no capex reduction, and now only 8 cents higher than its non-cluster counterpart at 10% DR. The results clearly demonstrate that a reduction in capex is required for cluster wells to be economically competitive with non-cluster wells, especially in a low gas price environment.

Discount Rate	Non-cluster breakeven price for given Discount Rate	Cluster breakeven price for given DR w/ 25% Capex reduction	Absolute difference of non-cluster and cluster BE	Percent difference (increase) in Cluster BE price
0%	$2.94	$3.09	$0.15	5%
2%	$3.07	$3.21	$0.14	4%
4%	$3.21	$3.33	$0.12	4%
6%	$3.34	$3.44	$0.10	3%
8%	$3.47	$3.56	$0.09	3%
10%	$3.60	$3.68	$0.08	2%
12%	$3.72	$3.79	$0.06	2%
14%	$3.84	$3.89	$0.05	1%
16%	$3.95	$3.99	$0.04	1%
18%	$4.06	$4.09	$0.03	1%
20%	$4.16	$4.18	$0.01	0%

Table 5 Breakeven prices for cluster wells and non-cluster wells with a 25% reduction in drilling capex

With the essential parts, q_0, production decline, and well cost, established the next step was to analyze the average well from a project perspective. By using the average well values with a certain expectation for natural gas price, a general overview of production and profit can be demonstrated. Taking the perspective of an operator, the respective average wells were evaluated using a $4.00 gas price with a 10% DR. Cluster wells were considered with a 25% reduction in drilling capex (Table 6).

$4 HH	Total EUR (MCF)	EUR Per Well (MCF)	NPV Cluster @ 10% DR	NPV per well @ 10% DR	IRR	PVI @ 10% DR
2 Cluster	3,736,959	1,868,480	$445,343	$222,672	16.2%	0.10
3 Cluster	5,605,439	1,868,480	$668,015	$222,672	16.2%	0.10
4 Cluster	7,473,918	1,868,480	$890,686	$222,672	16.2%	0.10
5 Cluster	9,342,398	1,868,480	$1,113,358	$222,672	16.2%	0.10
1 Non-Cluster	2,477,650	2,477,650	$369,738	$369,738	16.9%	0.12
2 Non-Cluster	4,955,299	2,477,650	$739,477	$369,738	16.9%	0.12
3 Non-Cluster	7,432,949	2,477,650	$1,109,215	$369,738	16.9%	0.12

Table 6 Production and economic metrics for different amounts of cluster and non-cluster wells

Operators have choices when drilling a particular acreage or project as shown by comparing total EUR, total NPV, IRR, and PVI for the project as well as the EUR and NPV per well (Table 6). First, non-cluster wells had per well NPV of $369,738 while cluster wells had a NPV of $222,672. The reduction in NPV of cluster wells is explained by the reduction in gas recovery seen in the production and decline results section. Since an increase in the number of wells is an increase in the number of average wells there is no change in IRR or PVI within the well classes. However, average non-cluster wells show slightly higher IRR and PVI than cluster wells. The average non-cluster well has a 16.9% IRR while the average cluster well has a 16.2% IRR. While very close, the non-cluster wells appear to be better economically, especially when considering the increase in initial investment cost from the additional wells used for cluster drilling. PVI also depicts non-cluster drilling as a better drilling pattern when considering the value or efficiency of the initial capital investment. Non-cluster wells have PVI of 0.12 and cluster wells have a PVI of 0.10.

The data shows non-cluster drilling is the better drilling pattern for gas recovery (EUR), project income (NPV) and monetary efficient (PVI) per well. However, the goal of the operator may not always be efficient use of their capital, which translates to choosing the project with the highest possible PVI.

An operator may choose the cluster pattern from a growth or resource perspective. Drilling the cluster pattern allows an operator to squeeze more wells into the same area. By doing so the operator more efficiently utilizes their most valuable resource, the shale formation. More intensely drilling the acreage translates to higher recovery efficiency per unit volume and higher sales. While the value of their capital investment may decrease, by selecting cluster drilling the total NPV for a particular acreage may be higher than choosing non-cluster drilling.

Thus, when comparing production and economics, it could be more appropriate to compare a three well cluster group to one or two non-cluster wells, than it is to compare an equal number of cluster and non-cluster wells. If an operator has acreage capable of drilling two or three non-cluster wells or using cluster drilling to achieve four to five wells the average outcome of NPV and EUR can be estimated (Figures 18 and 19). The two figures below provide a visual for the number of each different class of well needed to reach certain values of NPV or EUR.

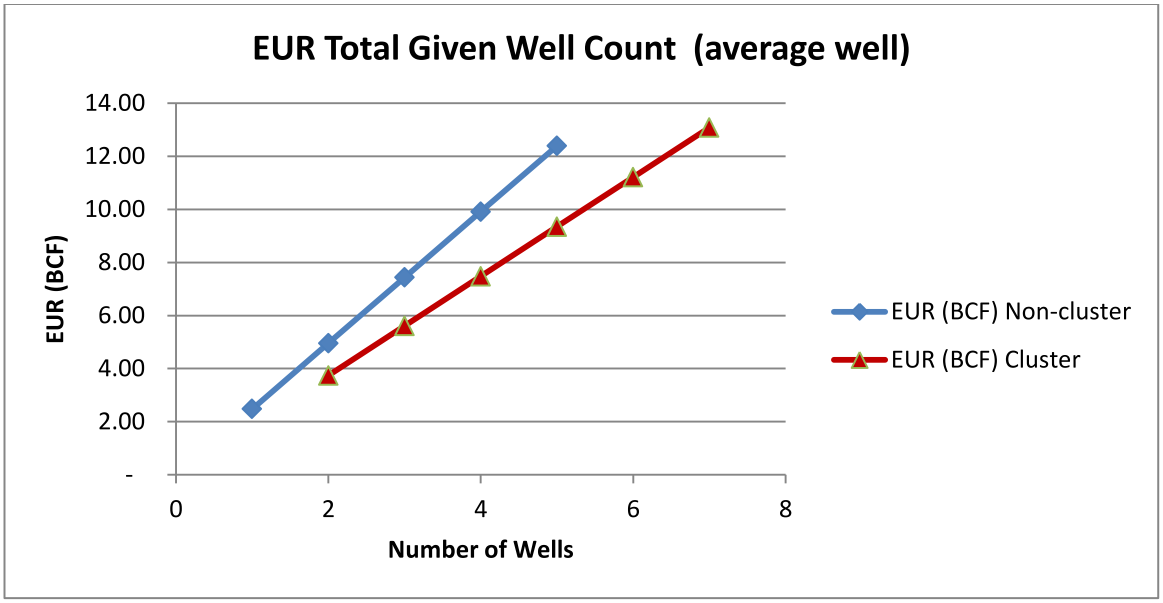

Figure 18 EUR of a lease given the number of cluster or non-cluster wells

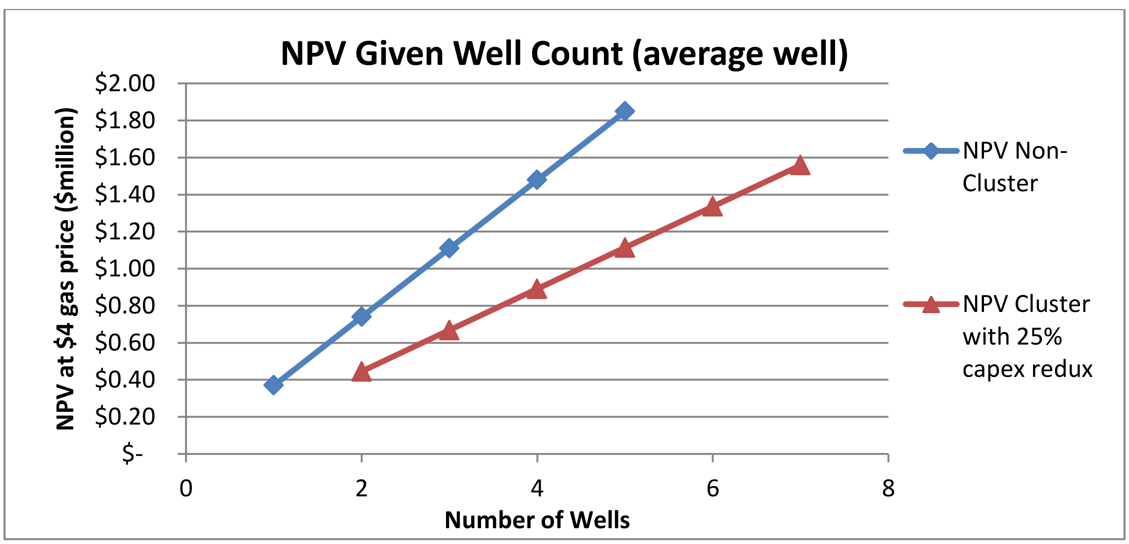

Figure 19 NPV of a lease given the number of cluster or non-cluster wells

4.4 Lease Examples

Finally, actual lease examples were used to assess the trend provided by the analysis of the average cluster and non-cluster wells. The first example compares one non-cluster well to three cluster wells in close proximity and drilled within one year of each other (Figure 20). By choosing the non-cluster analog that close in proximity and drilling time I have tried to minimize geology heterogeneities and completion technique variation. Analysis was performed with the same economic model and same average production profile; the only change was the utilization of each well's actual q_0.

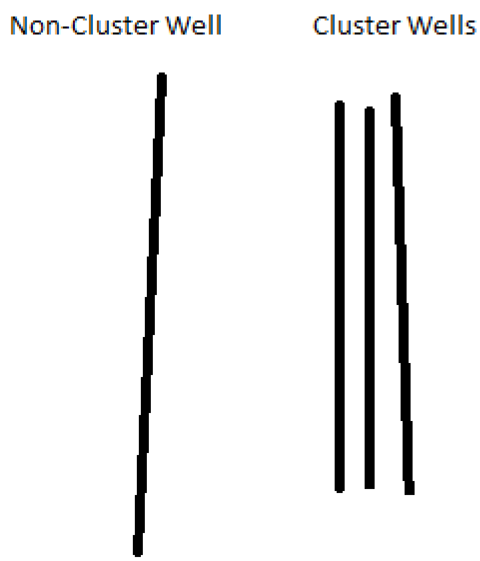

Figure 20 The proximity and relative length of cluster wells (3) and the non-cluster well (1) analog for production and profitability comparison

Considered with $4.00 Gas Price	Per Well q_0 (MCF)	Average Well q_0 (MCF)	EUR (BCF)	Total NPV@ 10% DR	NPV per well @ 10% DR	IRR	PVI@ 10% DR	Investment (M$)
Cluster 1	683,597	716,965	7.46	$ 2,677,970	$892,657	45%	0.40	6.75
Cluster 2	622,833							
Cluster 3	844,466							
Non-Cluster 1	1,012,631	1,012,631	3.91	$ 1,917,149	$1,917,149	68%	0.64	3.0
Difference between Non-cluster and cluster		29%	-91%	-40%	53%		38%	-125%

Table 7 Production and economic estimates for cluster wells (3) and the non-cluster well (1) analog

This example shows the dynamics of analyzing typical cluster and non-cluster wells. The non-cluster well is superior in per-well production, NPV, and monetary value (Table 7). However, when comparing all 3 cluster wells to the single non-cluster well, the cluster pattern generates higher total EUR and total project NPV. An operator in this scenario could have a decision; make more total NPV or maximize the value of the initial investment. This assumes the operator has the additional $3.25 million to drill two extra wells.

The second example has 3 non-cluster wells compared to 5 cluster wells. The wells are located in close proximity, drilled within one year of each other, and very close in length (Figure 21). Analysis was again performed with the same economic model and same average production profile; the only change was the utilization of each well's actual q_0.

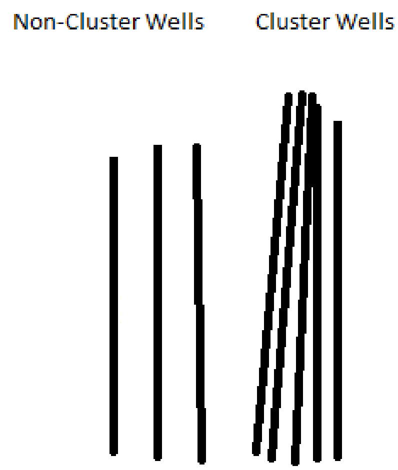

Figure 21 The proximity and relative length of cluster wells (5) and non-cluster wells (3) for production and profitability comparison

Considered with $4.00 Gas Price	Per Well q_0 (MCF)	Average Well q_0 (MCF)	Total EUR (BCF)	NPV@ 10% DR	NPV per well @ 10% DR	IRR	PVI @ 10% DR	Investment (M$)
Cluster 1	628,247							
Cluster 2	589,206							
Cluster 3	624,024	652,326	11.3	$ 3,286,061	$ 657,212	32%	0.29	11.25
Cluster 4	677,580							
Cluster 5	742,575							
Non-Cluster 1	732,239			$ 752,966	$ 752,966	25%	0.25	3
Non-Cluster 2	1,116,908	860,432	10.0	$ 2,354,370	$ 2,354,370	98%	0.78	3
Non-Cluster 3	732,149			$ 752,587	$ 752,587	25%	0.25	3
3 Non-Cluster Total				$ 3,859,922	$ 1,286,641		0.43	9
Difference between Non-cluster and cluster			-14%	15%	83%		32%	-25%

Table 8 Production and economic estimates for cluster wells (5) and the non-cluster well (3) analog

This particular example again shows the 3 non-cluster wells with higher monetary efficiency with a PVI of 0.43 compared to 0.29 for the 5 cluster wells. Interestingly, the 3 non-cluster wells also outperformed the cluster wells in Total NPV $3.8 million to $3.3 million (Table 8). In this second example the surface area covered by the two well groups are much closer and one could assume the drainage area to be similar. The five cluster wells demonstrate a better total recovery factor EUR 11.3BCF compared to just 10.0BCF for the three non-cluster wells. However, the higher total gas production came with a higher cost, $11.25 million, and resulted in lower project NPV.

While the examples continue to show an increase monetary efficiency and possible NPV out-performance of non-cluster drilling over cluster drilling, one factor cannot be over looked, gas recovery factor. The utilization of cluster drilling and increasing the number of wells within a plot of land will increase the total gas recovered from a similar volume of rock. Just as example two demonstrates, an operator may be willing to sacrifice monetary value and even NPV if they are increasing the performance and recovery of their resource.

Chapter 5: Conclusion

The development of new technology will continue to make unconventional shale gas resources more accessible. It is important to analyze every new technology in terms of productivity and profitability, as the knowledge gained will only further improve operational decisions in the oil and gas industry. This study used cluster-drilling technology in the Fayetteville Shale to illustrate a new technology's effect on productivity and profitability. A combination of historical production data and production profiles were used in a discounted cash flow model to quantify the changes in productivity, cost, and profitability. The analysis shows cluster-drilling technology must save at least 25% in drilling capital expenditure to be economically competitive with non-cluster drilling. The average Fayetteville cluster well recovers less natural gas, EUR of 1.9 BCF compared to 2.5 BCF for the average non cluster well; has a lower NPV of $222,672 compared to $369,738; and is a less efficient use of investment, PVI 0.10 to 0.12, than the average Fayetteville non-cluster well.

Cluster drilling technology lowers per well production and profit, but it can help operators in their per-acre gas recovery efficiency, which leads to more natural gas sold. However those benefits come with certain sacrifices, two being less finical flexibility as more money is tied into an acre and a reduction in monetary efficiency. Thus a company more concerned with growth will choose cluster technology and high upfront cost in order to receive a higher return. If an operator is more conservative or wishes to allocate a smaller portion of their finances into a project, non-cluster drilling will return the best value for their investment. Since the current gas price environment is low, operators may decide to go back to non-cluster drilling as a way to more efficiently use their monetary resources.

The effect of cluster drilling in the Fayetteville Shale may be enhanced with additional research. Introducing the volume variable, which was not in the scope of this study, may provide more detail into a well's recovery factor. Completion and microseismic data could allow for more detailed cost considerations and clarify the amount of gas produced from a certain stimulated rock volume.

The examples discussed in the results section demonstrate how variable productivity and profitability may be within the play no matter the drilling pattern. That variability is often due to geologic heterogeneities yet to be understood or accounted. Even if one decides to use cluster technology, there is no guarantee that the project will be a success. If the OGIP of the drilled rock is too low, neither drilling pattern can be profitable. Furthermore, a new technology working in one play may not translate that success to a different shale play.

Based on the history of the industry, cluster-drilling technology in the Fayetteville Shale may continue to change. One could assume those changes will benefit production and profit but may not be as monetarily efficient as older processes. Implementation of cluster drilling technology, or any technology with less monetary efficiency, may ultimately provide the most insight into an operator's current operational strategy. In this circumstance the operator has become more efficient with their resource and less efficient with their capital.

References

BP, 2014. *BP Energy Outlook 2035*.

Browning, J. et al., 2013. Barnett Shale Model–1: Study develops decline analysis, geologic parameters for reserves, production forecast. *Oil & Gas Journal*, 111(8), pp.63–71. Available at: http://gaia.pge.utexas.edu/papers/OGJPart-1.pdf.

Browning, J., Tinker, S. & Ikonnikova, S., 2014. Study develops Fayetteville Shale reserves, production forecast. *Oil & Gas …*. Available at: http://www.beg.utexas.edu/info/docs/Fayetteville Shale OGJ article.pdf.

Burgess, N. & Sartoretto, A., 2014. *SWN Investor Presentation June 2014*.

Cheng, Y., 2012. Impacts of the Number of Perforation Clusters and Cluster Spacing on Production Performance of Horizontal Shale-Gas Wells. *SPE Reservoir Evaluation & Engineering SPE-138843-MS*, 15(1), pp.31–40.

Dunn, D. et al., 2015. EIA Monthly Energy Review March 2015.

EIA, 1998. Annual Energy Outlook 1998 With Projections to 2020.

EIA, 2014a. Annual Energy Outlook 2014. *Doe/Eia*, 0383, pp.1–269.

EIA, 2014b. Shale gas provides largest share of U.S. natural gas production in 2013 - Today in Energy - U.S. Energy Information Administration (EIA). Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=18951 [Accessed April 17, 2015].

EIA, 2015. U.S. Natural Gas Marketed Production (Million Cubic Feet). Available at: http://www.eia.gov/dnav/ng/hist/n9050us2A.htm [Accessed April 8, 2015].

Ford, R. et al., 2011. Efficiently Developing Fayetteville Shale Gas Reserves : Percussion Drilling Solves Application Challenges / Reduces Drilling Costs. *SPE-148828-MS*.

Gulen, G. et al., 2014. Fayetteville Shale-Production Outlook. *SPE Economics & Management SPE-173187-PA*, 7(02), pp.1–13.

Harpel, J. et al., 2012. Case History of the Fayetteville Shale Completions. *SPE-152621-MS*.

Hazman, C. et al., 2008. Successful Application of Cluster Drilling Concept to Reduce Cost and Increase Profitability in a Mature Onshore Gas Field in East Kalimantan. *SPE-116537-MS*.

Higley, D. et al., 2014. Assessment of undiscovered oil and gas resources of the Anadarko Basin Province of Oklahoma, Kansas, Texas, and Colorado, 2010. *USGS Publication: Digital Data Series 69-EE*. Available at: http://pubs.usgs.gov/fs/2011/3003/pdf/FS11-3003.pdf.

Ikonnikova, S. et al., 2015. Profitability of shale gas drilling: A case study of the Fayetteville shale play. *Energy*, 81, pp.382–393. Available at: http://linkinghub.elsevier.com/retrieve/pii/S0360544214014236.

Ikonnikova, S. et al., 2014. Well Recovery , Drainage Area , and Future Drill-Well Inventory : Empirical Study of the Barnett Shale Gas Play. *SPE Reservoir Evaluation & Engineering SPE-171552-PA*.

Male, F. et al., Analysis of gas production in the fayetteville formation using scaling methods, in review.

McGlade, C., Speirs, J. & Sorrell, S., 2013. Unconventional gas - A review of regional and global resource estimates. *Energy*, 55, pp.571–584. Available at: http://dx.doi.org/10.1016/j.energy.2013.01.048.

Mian, M.A., 2011. *Project economics and decision analysis* 2nd ed., Penn Well Corporation.

Moniz, E.J., D., J.H. & Meggs, A.J.M., 2011. *The Future of Natural Gas Production An Interdisciplinary MIT Study*,

Patzek, T.W., Male, F. & Marder, M., 2013. Gas production in the Barnett Shale obeys a simple scaling theory. *Proceedings of the National Academy of Sciences of the United States of America*, 110(49), pp.19731–6. Available at: http://www.pubmedcentral.nih.gov/articlerender.fcgi?artid=3856843&tool=pmcentrez&rendertype=abstract.

Rafiee, M., Soliman, M.Y. & Pirayesh, E., 2012. Hydraulic Fracturing Design and Optimization : A Modification to Zipper Frac. *SPE-159786-MS*.

Sahai, V. et al., 2011. Optimal Well W Spac cing Conf figuration ns for Un nconvent ional Gas s Reservo oirs. *SPE-155751-MS*.

Sieminski, A., 2014. Outlook for U. S. shale oil and gas.

Southwestern Energy, 2015a. Fayetteville Shale | Southwestern Energy. Available at: http://www.swn.com/operations/pages/fayettevilleshale.aspx [Accessed April 8, 2015].

Southwestern Energy, 2015b. Our History | Southwestern Energy. , p.Our History page. Available at: http://www.swn.com/aboutswn/pages/ourhistory.aspx [Accessed April 14, 2015].

Speight, J.G., 2012. *Shale Oil Production Processes* 1st ed., Gulf Professional Publishing.

Wang, Q. et al., 2014. Natural gas from shale formation - The evolution, evidences and challenges of shale gas revolution in United States. *Renewable and Sustainable Energy Reviews*, 30, pp.1–28. Available at: http://dx.doi.org/10.1016/j.rser.2013.08.065.

Weijermars, R., 2014. US shale gas production outlook based on well roll-out rate scenarios. *Applied Energy*, 124, pp.283–297. Available at: http://dx.doi.org/10.1016/j.apenergy.2014.02.058.